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Hitachi's Carbon Dioxide Scrubbing Technology with H3-1 Absorbent for Coal-Fired Power Plants

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Abstract

Babcock-Hitachi K.K. (BHK) has been developing a new amine-based scrubbing technology for capturing CO_2 in the flue gas. By screening more than thirty kinds of amines, proprietary solvent H3 was developed in early 1990's that has high CO_2 absorption capacity and requires low regeneration energy. The H3 solvent was further improved to an advanced formulation called H3-1 by using additives to achieve 70% lower degradation rate compared with the H3 solvent. Tests of H3-1 to date by both BHK and others show that the reboiler heat duty for H3-1 was about 30% lower than that of 30% MEA solution. The H3-1 solvent was recently tested for over 1300 hours at a slipstream test facility sponsored by the United States Department of Energy. In partnership with SaskPower, Hitachi will demonstrate the H3-1 solvent at a 20MWth facility which will be installed at SaskPower's Shand Power Station in Canada. The facility will incorporate core process equipment designed and fabricated by Hitachi.

Selection and/or peer-review under responsibility of GHGT

Keywords: CO_2,; chemical absorption; amine; MEA; scrubbing

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1. Introduction

BHK, one of the Hitachi group companies, has been developing new technologies including amine-based scrubbing, oxy-fuel combustion, IGCC with CO_2 absorption, and 700°C class advanced ultrasupercritical boiler-turbine system, to tackle the issue of global climate change.

Amine-based CO_2 separation has been utilized since the 1930s for applications such as natural gas purification. It is a leading technology expected to be commercially available within the next decade to enable carbon capture and storage (CCS) for coal-fired power stations. However, the traditional amine-based CO_2 separation process utilizing conventional solvents is very energy intensive when applied to coal-fired power plants and the solvent is susceptible to degradation by oxygen, SOx and NOx present in the flue gas, resulting in drastically reduced plant efficiency and output as well as large operating cost. According to recent DOE/NETL studies, monoethanolamine (MEA)-based CCS will increase the cost of electricity (COE) of the latest pulverized coal plant by 80-85% and reduce the net plant efficiency by about 30%[1].

To address the challenges of making amine-based CCS practical for coal power, BHK has been developing a new amine-based scrubbing technology for capturing carbon dioxide in the flue gas for coal-fired power plants. The technology features an advanced Air Quality Control System (AQCS) for flue gas pre-cleaning, a low energy-consuming, highly oxygen-resistant amine-based scrubbing system, and a highly efficient steam extraction system. One of key components in AQCS is Flue Gas Desulfurization (FGD). As demonstrated in various coal-fired plants in the world, the BHK FGD is capable of reducing sulfur oxides to extremely low levels, which makes the downstream CO_2 scrubbing system more efficient and compact [2].

The solvent development program includes testing of various combinations of absorbents and additives. More than thirty kinds of amines have been evaluated and characterized by fundamental tests in the laboratory at BHK and slipstream tests of coal-fired flue gas in a commercial plant. Based on data from these tests, a desirable combination of amine and additives was chosen as an appropriate absorbent for coal-fired flue gas to achieve high absorption efficiency and low reagent degradation. These innovations are key for lowering the energy consumption of the CO_2 capture system.

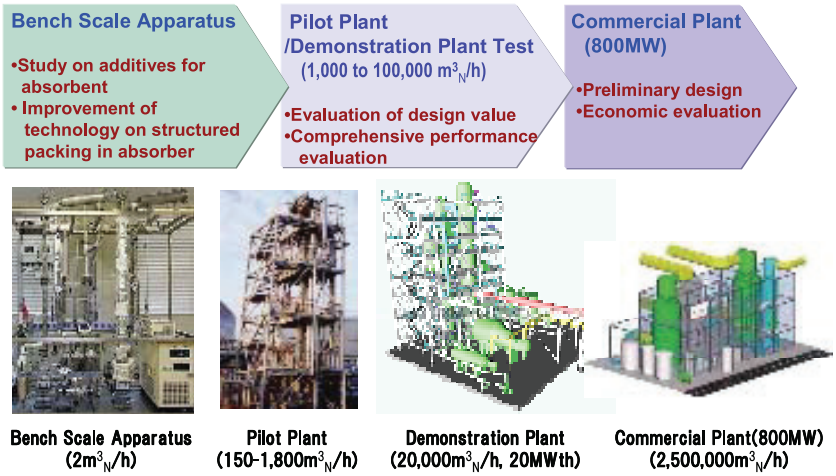

Figure 1: Roadmap from Bench Scale Apparatus to Commercial Plant

Figure 1 shows Hitachi's roadmap for CCS from the bench-scale testing facility at BHK to conceptual design developed for an 800 MWe commercial power plant. In cooperation with SaskPower, Hitachi designed process equipment will be installed in a 20 MWth carbon capture test facility (CCTF) where the H3-1 solvent is scheduled to be demonstrated in mid-2014.

2. CO_2 Capture Process Description

Figure 2 shows a sketch of a post-combustion CO_2 capture process. The main system components are a pre-scrubber, an absorber, a stripper and a reboiler. The CO_2 capture system is located downstream of the AQCS of a power plant. The gas cooler in AQCS is an original technology developed by BHK, to reduce the electrostatic precipitator (ESP) inlet gas temperature in order to remove particulates and trace elements in high efficiency across the ESP. The energy recovered by the gas cooler can be utilized for the CO_2 capture system to reduce its overall energy consumption.

Since SOx in flue gas is efficiently removed by the ESP, FGD and pre-scrubber, Hitachi can provide a CO_2 scrubbing system without a continuous reclaimer.

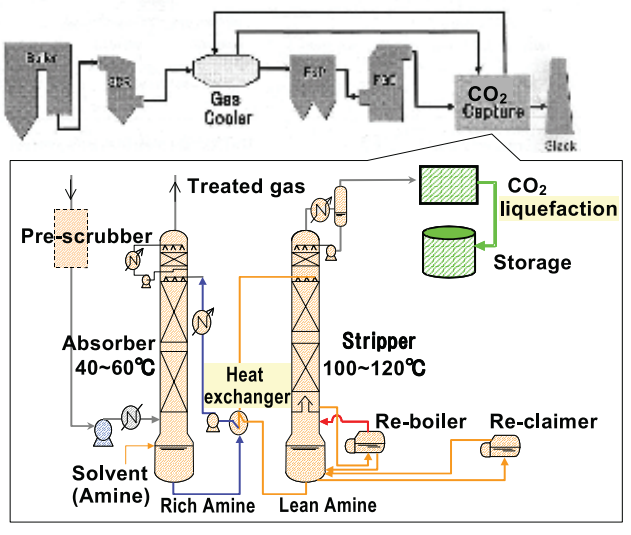

Figure 2: Post-Combustion CO_2 Capture Process

3. Development of H3-1 Solvent

BHK developed the proprietary H3 solvent by screening combinations of amines and additives in a 2 m^3N/h bench scale apparatus, shown in Figure 1.

During the pilot plant test operation conducted at the Yokosuka Thermal Power Station unit 2 in co-operation with Tokyo Electric Power Company in the early 1990s, it was observed that the capacity of the amine solution for CO_2 absorption was reduced by oxidation due to dissolved oxygen, by acid impurities such as SOx or NOx, and due to solvent loss as mist or vapor[3]. This gradual deterioration of absorption capacity would result in high solvent usage and operating costs. Therefore, the H3 solvent was improved by treatment with additives to minimize amine degradation and loss.

A range of additives, antioxidants and their combinations were screened in bench-scale apparatus. Figure 3 shows some results of the screening tests. Degradation of the H3 absorbent treated with additive-A group was over 70% lower than that of the solvent treated with other commercially available additives.

Additionally, the H3 solvent was improved to reduce amine loss. The H3 solvent was treated with another additive-B group. Amine loss of H3 absorbent treated with additive-B group was over 70% lower than the untreated H3 solvent, as shown in Figure 4.

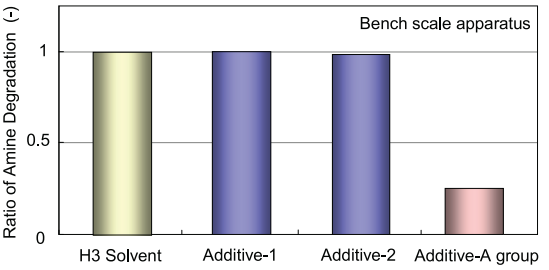

Figure 3: Influence of Additives on Amine Degradation

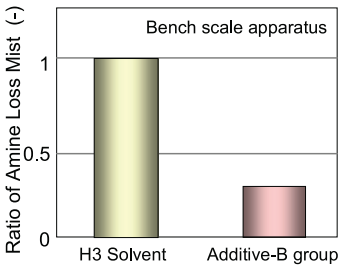

Figure 4: Influence of Additive-B on Amine Loss

After numerous screening tests an appropriate combination of the base amine, additive-A and additive-B was chosen as an advanced version of H3 solvent named H3-1. Both additives were chemically well-suited and had little influence on the amine performance of high CO_2 absorption and low regeneration energy requirement. Degradation of H3-1 solvent was reduced by more than 70% compared to that of H3 solvent, as shown in Figure 5.

Figure 6 shows the regeneration heat per unit weight of CO_2 captured for the two Hitachi solvents compared with MEA solution. The heat of regeneration of H3-1 and H3 solvents is about 30% lower than that for MEA solution. Figure 7 shows the amine loss for the three solvents. The amine loss of H3 solvent is about 70% lower than that of MEA solution. The amine loss of H3-1 solvent was about 85% lower than that of MEA solution. Solvent consumption and operating cost of a CO_2 capture process can be reduced further by using the improved H3-1 solvent compared with H3 solvent.

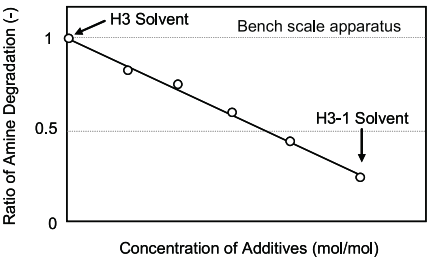

Figure 5: Influence of the Additive Concentration on Degradation of H3 Solvent

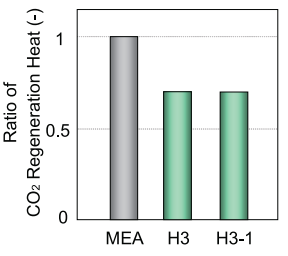

Figure 6: Regeneration Heat

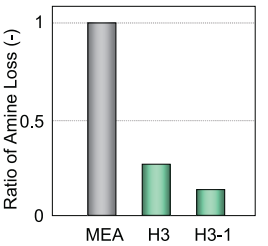

Figure 7: Amine Loss

4. Testing on the 500Nm^3/h Facility

Figure 8 shows a schematic of the 500Nm^3/h test facility and photographs of the stripper and reboiler at the CO_2 capture R&D center at BHK works. This test facility is equipped with an absorber, stripper, reboiler, reclaimer and vapor recompression system. Simulated flue gas containing air and CO_2 is saturated with H_2O by mixing with steam, and fed into the bottom of the absorber. CO_2 is scrubbed in the absorber by H3-1 solvent and the solvent is circulated to feed the stripper. CO_2-rich H3-1 solvent is heated by steam which is generated in the reboiler, and CO_2 is stripped. Table 1 shows specifications of the test facility.

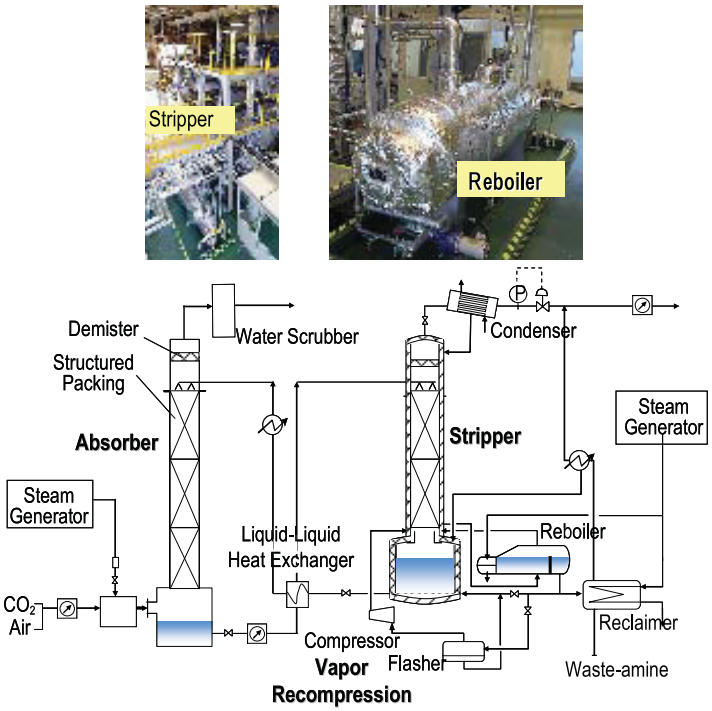

Figure 8: 500Nm^3/h Test Facility

Table 1: Specifications of the Test Facility

Gas Flow Rate	**250-850 Nm^3/h**
Liquid Circulation Rate	**5-60 L/min**
Reboiler Steam Rate	**150-190 kg/h**
Stripper pressure	**0.1-0.3 MPa**

Typical test results are shown in Figure 9 and 10. Figure 9 shows the relationship between the liquid-gas ratio (L/G) and CO_2 removal efficiency at two different inlet levels of CO_2. And based on those results, the volumetric mass transfer coefficient (Kga) is evaluated. Figure 10 shows the relationship

between L/G and Kga. The value of Kga increases with increasing L/G. These data are used to design absorber and stripper columns.

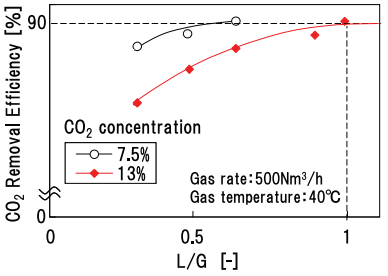

Figure 9: Relationship between L/G and CO_2 Removal Efficiency

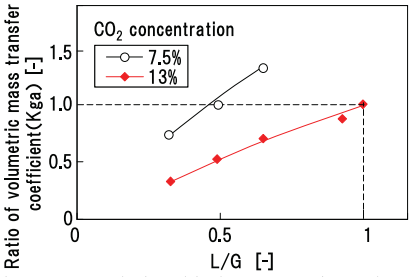

Figure 10: Relationship between L/G and Kga

5. EERC Test Results

The performance of H3-1 solvent was evaluated in the pilot scale test facility at the Energy and Environmental Research Center (EERC) in USA. Figure 11 shows the EERC pilot plant equipped with a coal fired furnace, flue gas clean up system and CO_2 capture facility. Coal-fired flue gas passes through the SCR, ESP and wet-FGD where NOx, particulate matter and SOx are removed and the flue gas temperature decreases. This cooled flue gas, at 30-50°C is introduced to the CO_2 absorber. Table 2 shows the absorber inlet gas conditions. The pilot plant was operated using H3-1 under various conditions and the performance results were compared with MEA[5].

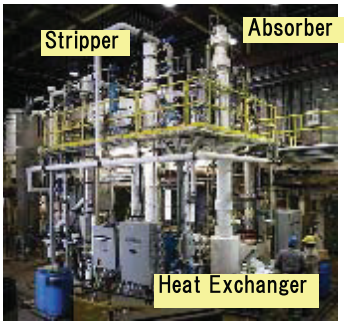

Figure 11: EERC Pilot Plant

Table 2: Absorber Inlet Gas Conditions

Item	Typical Range	Unit
Flow Rate	100-200	Nm^3/h
Temperature	30-50	℃
CO_2 Concentration	16	%
NOx Concentration	0-600	ppm
SO2 Concentration	0-600	ppm

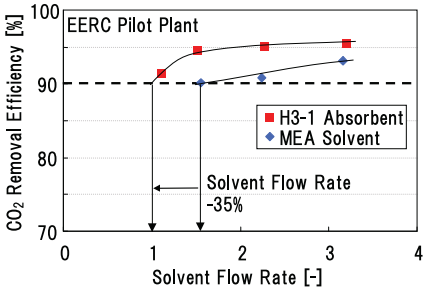

Figure 12: Relationship between L/G and CO_2 Removal Efficiency

Figure 12 shows the relationship between the liquid-gas ratio and CO_2 removal efficiency. At 90% CO_2 removal efficiency, the required solvent recirculation rate for H3-1 was about 35% lower than that for MEA. The heat duty in the reboiler when using H3-1 as the solvent was about 30% lower than with MEA.

6. Test at NCCC

Recently, The H3-1 solvent was tested in the pilot scale test facility at the National Carbon Capture Center (NCCC). A slipstream gas from a coal-fired boiler was fed to the test facility after passing through an SCR and wet-FGD. This flue gas was then introduced to the prescrubber where SO_2 and other trace components were removed. The flue gas was then passed through a cooler-condenser where the gas temperature was reduced to the controlled level, before being introduced to the CO_2 capture system. Figure 13 shows a sketch and a photo of the pilot plant facility. This CO_2 capture pilot facility is equipped with an absorber, stripper, heat exchangers, a washing tower, inter coolers and a reboiler[6]. Over 1,300 hours of testing of the H3-1 solvent was completed and the results will be discussed later.

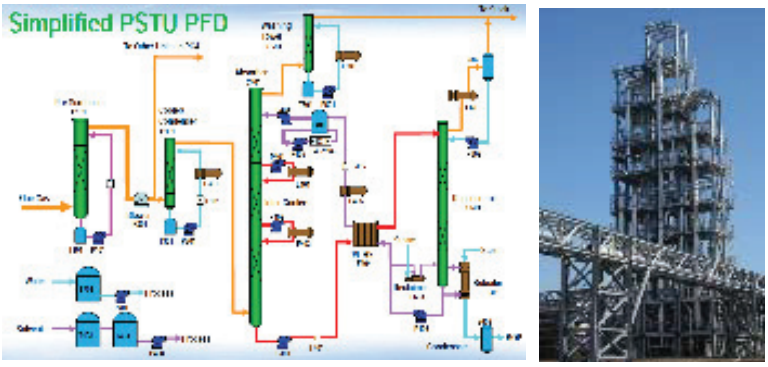

Figure 13: NCCC Pilot Plant

7. CCTF Demonstration Plant

Hitachi and SaskPower, a utility company in Saskatchewan, Canada, have collaborated to design and build a 20 MWth Carbon Capture Test Facility at SaskPower's coal-fired Shand Power Station. The H3-1 solvent will be tested at this facility. The plant will provide slipstream flue gas at a flow rate of about 20,000Nm^3/h. Hitachi is currently working on the detailed design of process equipment for the facility. Construction is scheduled to start in 2013 and testing in mid-2014. Figure 14 shows the arrangement of the CCTF.

Figure 14: Arrangement of the Carbon Capture Test Facility at SaskPower

8. SUMMARY

- BHK has developed a proprietary amine-based solvent, H3-1, by screening more than thirty kinds of amines, additives and their combinations. Amine loss of the advanced H3-1 solvent is about 85% lower than that for 30% MEA solution.
- Solvent recirculation rate required for 90% CO_2 capture using H3-1 is about 35% lower than that with MEA. The heat duty in reboiler when using H3-1 is about 30% lower than that with MEA.
- A 20 MWth CO_2 capture demonstration plant at SaskPower's Shand Power Station will begin testing Hitachi's H3-1 solvent in mid-2014.

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